SEM Committee

c/o

gkelly@cru.ie

Commission for Regulation of Utilities
The Exchange
Belgard Square North
Tallaght
D24 PXW0

Gary.Mcculough@uregni.gov.uk.

Utility Regulator
Queens House
14 Queen Street
Belfast
BT1 6ED

RE: SEM Committee consultation on the Implementation of Article 12 and 13 of EU 2019/943 (SEM-20-028)

Dear Gina / Gary,

Coillte welcomes the opportunity to respond to the SEM Committee consultation (SEM-20-028, "the consultation") on the implementation of Article 12 and 13 of EU Regulation 2019/943 (the "Regulation") and would like to acknowledge the time and effort taken to prepare the consultation and to host the recent industry workshops which were very helpful.

Coillte's Objectives

Coillte is focused on enabling key national policy objectives that cover a range of industries including renewable energy, forestry, housing, healthcare, education, inward investment, infrastructure development, water, tourism and agriculture. In particular, Coillte is one of the largest developers of renewable energy in Ireland and has enabled in excess of 30% of all installed wind farms through wayleaves/rights of way and as a land supplier and developer. Coillte has identified an extensive pipeline of 1GW of new on-shore wind development for energisation on our lands by 2030 and the potential for further significant development thereafter. We therefore look to be a significant contributor to the transformation of the energy sector in the coming decades.

In the context of this consultation, our principle concern is that any new ruleset for the treatment of energy balancing and the sharing of the constraint/curtailment burden amongst renewable generators is:

- compliant with the Regulation;
- yields a scheduling and dispatch regime that is transparent and can be forecasted with low levels of system operation discretion / regulatory risk; and
- yields a compensation regime in conjunction with RESS support (or a corporate PPA) which supports efficient investment.

Such forecasting is important for the formulation of Renewable Energy Support Scheme offers, the auctions for which are planned to happen concurrently with this consultation process.

This consultation process is also likely to interact in a material way with future firm access policy as described further below.

Interaction with Non-Firm Connection Policy and impacts on PSO costs

Whether constraints are market based or non-market based, such generators are reliant on receiving firm grid access to be compensated to the level of financial support (be that through the Balancing Market rules with a negative decremental offer, or through some other Article 13 based mechanism). It is not reasonable for investors in new renewables to face material uncertainty as to when generators become firm. A non-firm connection regime which provides firmness at a difficult to predict future timeframe (and a consequent step-change in revenues) leads to inefficient generation development and unduly inflates prices requested in these long-term contracts.

In this context, it is important to note a key difference for consumers under a RESS vs REFIT regime. In REFIT, generators were unable to change their prices irrespective of the level of constraint or curtailment risk or uncertainty so a direct compensation model would not have resulted in reduced PSO costs. However in RESS all of these risks and uncertainties are passed straight on to consumers through increased auction bid prices. (i.e. Consumers will pay for the curtailment / constraint of generators irrespective of whether it is directly compensated or not). Where firm access is made available and compensation is paid directly, then the consumer pays the actual cost of this without any risk premium. If this is not directly compensated, the consumer pays the amount estimated by generators in their bid calculations with a risk premium. Commercially efficient contracts allocate risk to the party best placed to manage them. Generators have no ability to manage these risks whereas consumers, represented by SO's and RA's, do. As such it is extremely likely that consumers interests are better served with a move to a direct compensation model. In this respect we would also note that the analysis in the paper examining the cost of compensation does not appear to have taken any account of the impact of compensation on future bid prices.

Coillte is currently working to develop methodologies to evaluate and price this risk. This material would be commercially sensitive but should it be of interest to the SEMC or the RA's, we would be willing to engage separately to provide more details.

Response Summary

Coillte is an active member of the Irish Wind Energy Association ("**IWEA**") and our professional team actively participate in a number of IWEA committees. Our team have been involved in the preparation of the IWEA response and we wish to support and endorse the positions set out in their submission.

Coillte would also like to emphasise certain points in its own response, noting in particular that a further consultation will be required to inform certain **implementation principles** as part of any detailed design implementation. There are material risks that legal rights of compensation, the relative rights of priority dispatch and non-priority dispatch renewables, and policy directions may be critically distorted through implementation detail, particularly where both interim and enduring solutions may be envisaged.

It is particularly important that all renewable generators which can participate in the RESS auction have the same Priority Dispatch status in order to preserve fair competition in the auction process.

Figure 1 sets out a high-level conceptual schematic of the market design, noting which areas have been given extensive consultation (green), which areas are not open for consultation (highlighted in red boxes), and implementation detail areas which Coillte believes are critical to understanding the overall picture (orange).

The orange areas primarily relate to physical notifications, central scheduling and dispatch activities, the subsequent classification of those actions prior to Settlement, and the application of simple/complex or deemed Commercial Offers in that Settlement. It is these highlighted areas which can be implemented in many different ways, which can yield surprisingly different outcomes for market participants, irrespective of the original policy objectives.

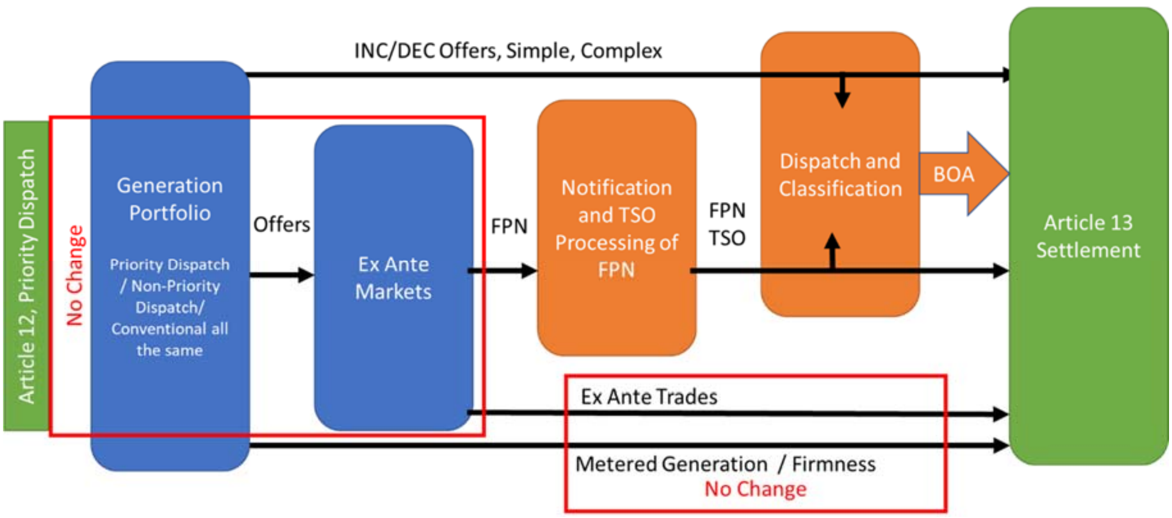

Figure 1: A Schematic of Trading, Scheduling and Dispatch, and Settlement in the SEM. Colour-coding refers to what elements are under consultation.

Areas that Can be Progressed to a Decision

Coillte believes there are certain questions raised in the Consultation which can progress rapidly to a decision. These include:

- Article 12: The meaning of "subject to existing contracts" at the time of the July 4th, 2019 date, which defines what are the last large generators which receive Priority Dispatch;
- Article 12: The meaning of "significant modifications" in relation to a power generating facility, the consequences of which Priority Dispatch may be lost;
- Article 13: Whether constraint is considered "non-market based" redispatch – if the SEM Committee wish to proceed with their current direction that constraint is "market-based" this will require material further consultation, as per the commentary below;
- Article 13: The principle whether compensation will be paid from the date of the decision, the date of the implementation of systems, or the date of legal effect (1st January 2020);
- Article 13: A position on the legal principle of payments being "unjustifiably high" in the context of non-market redispatch compensation, particularly at the level of financial support.

Note that unfortunately decisions in relation to the five areas specified above will not, solely by themselves, provide a sufficient level of detail to inform efficient RESS offers.

Coillte support's IWEA's call to set out a clear consultation and implementation roadmap to clarify the market design in a timely well-resourced manner.

Areas that will Require Further Consultation

1. **Proposed classification of constraints as "market-based re-dispatch"**

Coillte supports IWEA's position that constraint is non-market-based redispatch. If, however, the SEM Committee remains of the view that constraint should be treated as market-based redispatch, this opens up further weighty questions which were not addressed in the paper. Alongside the non-firm connection policy addressed above, the Balancing Market Bidding Code of Practice needs to be considered. Article 13 refers to a generator's right to be compensated at a market-based rate for redispatch. Where a generator cannot recover its full opportunity costs including the cost of lost subsidy under a firm connection offer under a market-based mechanism due to the regulatory intervention of the BMBCOP, this is no longer market-based compensation (the fact that compensation may flow through the T&SC does not necessarily mean that the compensation has been made at a competitive market rate). In short, it is Coillte's view that careful consideration is needed on whether the BMPCOP's application to all redispatch (aka SRMC complex offers applying to all non-energy actions) is consistent with the requirements of the Regulation.

2. Compensation for "non-market-based re-dispatch"

Coillte believes it is too early to engage materially with the options for compensation for curtailment presented in the paper while there is core disagreement on whether any of those options are compliant with Article 13.

3. Key Implementation Principles:

Coillte also believes the following proposed **Implementation Principles** should be adopted in consideration of any subsequent consultation / proposed decision.

- <u>Generation Declarations Need to be Technically Appropriate for Windfarms (including on an Interim Basis if Required) and if this Necessitates Changes to Market Systems, these Changes Should be Made.</u> Perverse commercial outcomes are likely to occur for different classes of renewables if they have to utilise the existing EDIL or Wind Dispatch tools without any modification.

- <u>Dispatch and Redispatch need to be Clearly Proceduralised and Modellable, Given the Importance of Delivered Energy to Renewable Generators.</u> Renewable Generators are in receipt of subsidy based on delivered power. If there are legal obligations to treat energy balancing and curtailment differently between windfarms with and without Priority Dispatch, and commercially binding 15-year contracts are being entered into on the basis of that legal understanding, the implementation must be robust. It should be clear what actions the TSO is likely to take for a given set of market and system conditions with regards to the renewables portfolio.

- <u>Dispatch Classification Rules need to be Clearly Defined and Aligned with the Dispatch Taken.</u> Coillte respectfully disagrees with the SEM Committee's assessment that central dispatch markets are more difficult than self-dispatch markets in the identification of dispatch and redispatch. If the two cannot be differentiated in real-time, then energy balancing that happens concurrently with curtailment cannot be accurately separated, and there is no point in having new renewables face energy balancing but sharing curtailment pro-rata with Priority Dispatch plant. Moreover, any (subsequent or real-time) classification of the actions must align with the form of dispatch taken, i.e. pro-rata curtailment shared between new renewables and Priority Dispatch renewables must be identified as a form of non-market based redispatch and settled as such. Where new renewables are turned down ahead of Priority Dispatch plant, this must be identified as energy balancing and also settled as such.

- <u>Detailed Settlement Rules should not Undermine the Principles of Compensation Agreed at a High Level.</u> The Trading & Settlement Code is complex, dealing with issues such as Biased Quantities (which adjusts the compensation payable when the TSO dispatches a generator away from its FPN, but the ex-ante traded volume is different to the FPN for that generator). Where:
  - FPNs may deviate from ex ante trades, and

- where a single dispatch action may have elements of dispatch and redispatch, and
- dispatch and redispatch are compensated differently,

it is important to know how such a Biased Quantity is allocated between dispatch and redispatch bid/offer acceptances.

- Rules around the deviation of FPNs from Ex Ante Traded Positions must be Fair and Equitable for all Generators. Detailed examples to follow in response to the questions will show how differing FPNs from conventional generators can in certain circumstances impact the classification of actions as dispatch or redispatch. Finally, there may be circumstances whereby RESS generators which have not achieved an ex ante position may wish to FPN at their available power, if the DAM price is positive. Conventional generators are afforded some techno-economic flexibility around the submission of FPN around their minimum generation. The allowed flexibility for FPNs to deviate from ex ante positions should be properly defined and granted to all forms of generation.

Responses to the specific consultation questions follow in the Annex below, including some illustrative examples. If you wish to discuss our response further, we would be amenable to meet with the SEM Committee or its representatives at a mutually convenient time.

Yours Sincerely,

[*Sent by email – no signature required*]

____

Paul Blount, BE CEng,
Portfolio Director

ANNEX

Responses to Individual Questions

Consultation Question 1: Do you agree with the RAs' interpretation of the requirements under Articles 12 and 13 and specifically the application of dispatch, redispatch and market based/non-market based redispatch in the SEM?

Response: There are a number of areas here which merit some clarification, and in certain cases disagreement.

Broadly speaking, Coillte agrees with the alignment SEM and Regulation terminology, i.e. of energy actions with dispatch and non-energy actions with redispatch. Coillte does have issues, however, with the legacy definition of curtailment and the apparent application of Priority Dispatch to dispatch only.

Energy Balancing / Dispatch and Curtailment for Priority Dispatch Renewables

Currently the definition of curtailment under SEM-13-010 implicitly contains an element of energy balancing for Priority Dispatch renewables when the sum of the available renewable generation exceeds the demand to be served. By means of example, if 3100MW of wind received an ex ante position today, demand was 3000MW, and wind was required to be dispatched down to 2000MW to achieve a secure dispatch, all 1100MW of dispatch down would be classified as curtailment. This example assumes for simplicity that conventional generation has achieved no ex ante position.

It is Coillte's understanding that within the context of the definition of "dispatch" within the Clean Energy Package that 100MW of such dispatch down would be classified as "energy balancing". This 100MW of wind would be settled at its DEC price (either submitted or deemed to be at €0/MWh).

Consequences of Constraint being Market Based-Redispatch?

Later in the paper it is contended that new and old renewables shall be treated equivalently for all forms of redispatch (Question 12). Coillte agrees with the SEM Committee that redispatch in analogous to non-energy actions, and includes constraint and curtailment. If constraint is market based redispatch for new renewables, however, it is also market based redispatch for Priority Dispatch renewables. This appears to be placing Priority Dispatch generation under a form of market merit order for redispatch, a diminution of the existing Priority Dispatch rights of such generators.

Coillte disagrees with this diminution of Priority Dispatch and concurs with IWEA that constraint should be considered a non-market based redispatch for both new and legacy Priority Dispatch renewables.

There is an implementation scenario whereby new renewables may be allowed to compete for market based redispatch for constraints. Priority Dispatch renewables would be left non-market based. This is problematic as most new renewables will be non-firm, will not be compensated at their DEC offer price, under the BMPCOP will not be able to reflect foregone subsidy, and therefore face material unpredictable grandfathering risk of constraint in the calculation of future revenues.

Consultation Question 2: In terms of the practical implementation of Article 12(1) to introduce a distinction between units which retain eligibility for priority dispatch and those which are not eligible, the RA's propose;

- Where a commissioning programme has been agreed with the TSOs on or before 4 July 2019, it is proposed that such units will be eligible for priority dispatch.
- Where a unit is eligible to be processed to receive a valid connection offer by 4 July 2019, the RAs are of the view that this represents a contract concluded before priority dispatch ceases to apply under Article 12 and that such units are also eligible for priority dispatch.
- Where a unit becomes active under a contract concluded before 4 July 2019 including a REFIT letter of offer or PPA, the RAs welcome feedback on the proposal for such generators to be eligible for priority dispatch.

Interested stakeholder's views are invited on these proposals.

Consultation Question 11: The RA's interpretation of the Regulation is that where a new connection agreement is required or where the generation capacity of a unit is increased, a unit will no longer be eligible for priority dispatch. The RAs also propose that units should be able to make a choice on whether they wish to retain their priority dispatch status or not. Feedback is requested on this proposal.

Response: Question 2 and Question 11 are taken together. Whatever approach is taken by the SEM Committee, all RESS-1 participants should either have Priority Dispatch or not have Priority Dispatch. It is Coillte's view that generators which have secured a route to market by 4th July 2020 under the anticipation of having Priority Dispatch should be considered to have a "contract concluded". Coillte supports IWEA's response on that basis.

Similarly, the Regulation states that a new connection agreement is "required" following a signification modification to a generating facility. Coillte believes that the Regulation allows pragmatic local-market flexibility to be taken in the interpretation of the Regulation. Coillte believes that the power generating facility should be defined as a Generator Unit in SEM. To that end, a significant modification should exclude:

- Any investment which would not be untypical during a normal life-cycle of a wind farm, including changes to the connection methodology or sharing/merging of the grid connection with another separately metered Generator Unit;
- Any standard lifecycle improvements to generator control systems, etc., to a Generator Unit, which is short of a substantial repowering;
- "New" connection agreements which were issued for procedural reasons, not because of a material change to the generator.

Coillte, Dublin Road, Newtownmountkennedy, Co. Wicklow, A63 DN25, Ireland.
T 1890 367 378 F +353 1 201 1199 E info@coillte.ie W www.coillte.ie

Consultation Question 3: It is the RAs' understanding that any unit which is non-renewable dispatchable but is no longer eligible for priority dispatch can be treated like any other unit within the current scheduling and dispatch process, through submission of PNs with an associated incremental and decremental curve. Feedback is requested on this aspect of implementation of Article 12 of the new Electricity Regulation.

Response:

Insofar as this question relates to conventional dispatchable generators acting under EDIL (and not variable renewable controllable generators), Coillte has no comments.

Consultation Question 4: It is proposed that any unit which is non-dispatchable but controllable and is no longer eligible for priority dispatch would run at their FPN, be settled at the imbalance price for any volumes sold ex-ante and could set the imbalance price.

As part of this proposal, there is a question of whether such units would be required to submit FPNs or where no FPN is submitted, the unit could be assigned a deemed FPN calculated by the TSOs as per the process today. Where a unit elects to submit an FPN, in this case, the TSOs would be required to use this as long as it does not deviate above a certain percentage of the TSOs' own forecast availability of the unit.

As an alternative or as a possible interim measure, taking account of the zero marginal cost nature of non-dispatchable but controllable generation in the market today, i.e. wind, solar, units no longer eligible for priority dispatch could be scheduled to their availability as per the process today on the assumption that this reflects economic dispatch in any case, but where there is excessive generation on the system such units would be subject to energy balancing prior to any priority dispatch units.

In particular, the RAs are seeking feedback from the TSOs on measures which can be introduced to facilitate required compliance with the new Electricity Regulation within the scheduling and dispatch and balancing market systems.

Response: This is an area which requires further consultation. It is possible that this may result in an "interim" solution followed by an "enduring" solution. Where the transition to one solution to another leads to a step change in dispatch behaviours, or in costs (e.g. a move from a renewables automated dispatch tool to some form of automated EDIL, for example), this leads to material risks for generators who have secured a long-term fixed price RESS or corporate PPA.

There are issues with shoe-horning non-Priority Dispatch renewables into any existing system.

- If a RESS generator is required to submit an FPN (at a defined MW level) and that FPN is respected, if there is no constraint or curtailment it will presumably be dispatched to that level. If the FPN is below the technical availability of that RESS generator to produce energy, it will have been inadvertently and inefficiently self-curtailed. This will lead to generators inflating their assumed FPN above their actual projected available power, which is difficult to monitor. It would be better if as part of a new solution the "unconstrained" FPN for a windfarm was "I wish to run at my available power", or the FPN could be automated to the windfarms availability much closer to real-time after Gate Closure, unless the windfarm wished to submit a MW value below its availability which it would commit not to exceed;

- Having an FPN assigned by the TSO for a RESS generator at its availability is unacceptable. It may wish not to generate if the Day-Ahead Price is negative. There is no guarantee that such a generator would be subsequently turned off in dispatch. The FPN methodology would effectively under certain circumstances force a class of generators to be dispatched at a loss.

It is most likely that an adjustment of the wind dispatch tool will be required. It is fundamentally unreasonable to expect a 10MW windfarm, for example, to implement the manual control and declaration processes of EDIL, including the costs of a 24-7 manual control centre. By means of a simple example, second-by-second manual entry of the windfarm's real time availability into EDIL is clearly not pragmatic.

Consultation Question 5: Feedback is invited from interested stakeholders on the treatment of non-dispatchable and non-controllable units.

Response:

Coillte's view is that as they are neither dispatchable nor controllable and are entitled to maintain that status under legacy Grid Code provisions, they are entitled to retain that status unless they participate in aggregation or choose to repower.

Consultation Question 6: Do you agree with the RA's interpretation that new generators which are no longer eligible for priority dispatch (both dispatchable and non-dispatchable but controllable) will be subject to energy balancing actions by the TSOs, considered in dispatch economically and settled like any other instance of balancing energy?

Response: Coillte agrees with this position, but the detail underneath requires further consultation and consideration before reaching a high-level decision. It is critical, however, given that the TSO will start with FPNs in determining what is an energy or non-energy action in real-time, that this interaction is understood by market participants and can be predicted sufficiently to model for upcoming and future long-term contracts.

Normally, generators are kept whole in the market one way or the other when their FPNs deviate from their physical dispatch. Generators should be dispatch indifferent, at least to the level of the short-run marginal costs. There are issues, however.

- Dispatch (energy balancing) can be compensated at the level of financial support if the generator is firm (unlikely for most new generators) and has achieved an ex ante trade (which can be problematic as well at times of over-supply of energy) and has submitted an appropriate decremental offer to recover the level of financial support in conjunction with the value of its ex-ante trade. If, however, the generator does not have firm access, under the existing market rules the generator would be required to purchase the dispatched down volume at the imbalance market price – and therefore clearly has no guarantee of recovering revenue at the level of financial support;

- Redispatch (constraint) is currently proposed by the SEM Committee to be market based for new generators. Further to the requirements of having an ex ante trade and a firm connection agreement, the offer will be subject to the BMPCOP and even if compensation is paid, it will not be guaranteed to be at the level of financial support; and
- Redispatch (curtailment) is currently proposed not to be compensated in full by the SEMC (despite Coillte's and IWEA's arguments that it should).

FPNs become critical. Take the following Scenarios A and B.

New renewables are subject to energy balancing first. They share curtailment with legacy priority dispatch plant. FPNs that diverge from the associated ex ante traded position will change the level of perceived energy balancing required relative to curtailment. For the first example, assume only wind is in the ex-ante markets.

- Scenario A. If 3,000MW of wind have FPNs relative to 3,000MW of demand, and wind needs to be curtailed to 2,000MW, that is clearly curtailment that should be shared pro-rata between new and old windfarms.
- Scenario B. If, however, there are 1,000MW of conventional FPNs (being a sufficient level for secure dispatch) and there still are 3,000MW of wind FPNs, the 1,000MW of wind to be turned down now may be assessed in real time as an energy imbalance. New renewables would take the dispatch down risk.

In Scenario B, the 1,000MW of conventional generation may have arisen either because they secured an ex ante trade, or they have an FPN higher than their traded position in order to provide technically feasible FPNs to the TSO. The 3,000MW wind may also have either secured an ex ante trade of 3,000MW, or may have FPNs (either submitted, or deemed at the available energy) greater than their traded position as well.

Consultation Question 7: What is your view on the application of bids and offers to zero marginal cost generation?

Response: Article 12 and 13 refers to **market-based** mechanisms for compensation for dispatch and redispatch. For redispatch in SEM, however, the SEM Committee has applied the BMPCOP (which does not allow inclusion of financial support in the formation of bids and offers). It is Coillte's view that the application of the BMPCOP and its restrictive interpretation of the opportunity costs faced by zero-cost variable generation (i.e. the exclusion of the subsidy) make all redispatch in SEM non-market based, and therefore subject to compensation at the level of financial support.

It is Coillte's opinion that further consultation is required in relation to this entire area. Redispatch is either:

- All non-market based, in which case compensation flows through Article 13. If the compensation is at the level of financial support, this is Coillte's preference. The question under these circumstances is moot as all generators will be kept whole for dispatch.
- Part market-based (constraint), part non-market based (curtailment). Under such circumstances the market based redispatch should not be subject to the BMPCOP.

Consultation Question 8: What is your view on a potential rule-set being implemented for non-dispatchable units where (a), systems cannot facilitate ranking of decremental bids for such units for balancing actions for a certain time period and/or (b) where convergent bid prices require a tie-break rule?

Response: Coillte's view is that best efforts pro-rata allocation of downwards redispatch or dispatch against the scheduled available generation is the most probable outcome in the balancing market. This would be broadly equivalent to how it is treated in the Day-Ahead Market as per the EUPHEMIA algorithm for trades, which provides a share of the available cleared volume across all similarly priced trades. Overall, however, any decision in relation to this is premature without wider context of the level of compensation to each type of generator caught in that tie-break.

Consultation Question 9: Do you agree with the TSO's proposal for a revised priority dispatch hierarchy? The RAs request that the TSO's consider the points raised in this Section in their response with any further proposed changes to the hierarchy.

Response: We concur with IWEA's response in relation to this matter.

We note the removal of TSO countertrading from the Priority Dispatch hierarchy. The Intraday Continuous market remains uncoupled with neighbouring markets, meaning the TSO is the only entity capable of altering interconnector flows closer to real-time. Within the context and the requirements of the European Network Codes, it is not clear to industry as to what tools are available to the TSO to countertrade, what activities are currently ongoing, and what Network Code restrictions (if any) are preventing such activities minimising downward redispatch of renewables as required under Article 13 (5) of the Regulation.

Consultation Question 10: Feedback is requested from interested stakeholders on the types of demonstration projects that may be suitable for an application process for limited priority dispatch eligibility.

Coillte, Dublin Road, Newtownmountkennedy, Co. Wicklow, A63 DN25, Ireland.
T 1890 367 378 F +353 1 201 1199 E info@coillte.ie W www.coillte.ie

Response: Demonstration projects, if granted priority dispatch, should be a) unique at the European level within the scope of the Regulation, and b) the Priority Dispatch should be time-limited from the date of energisation to avoid "rewarding" project delays, subject to any delays which can be demonstrated to be outside the control of the demonstration project.

Consultation Question 12: Do you agree with the RAs' interpretation of Article 13(5)(b) whereby downward redispatching of electricity produced from renewable energy sources or from high-efficiency cogeneration (i.e. the application of constraints and curtailment) regardless of priority dispatch status, should be minimised in the SEM? Under this interpretation, the only difference between renewable generators and HECHP eligible for priority dispatch will be how they are treated in terms of energy balancing.

Response: We agree with the interpretation in the first sentence. It is difficult, however, to reconcile it with the view that constraint for such sources of generation are market based redispatch. If constraint is market based redispatch, does this imply two different commercial merit orders for market-based redispatch, one for renewables / HE CHP, and another (lower priority with a small "p") for conventional generation?

It is cleaner to define all redispatch of renewables and HE CHP as non-market based.

In relation to the sentiment in the second sentence, if constraint is market based redispatch and new and old renewables are to be treated equivalently, this would represent a diminution of the Priority Dispatch status of existing generators.

Again, the solution appears to be to a) agree with statements in Consultation Question 12, but b) only in the context where redispatch of renewables and HE CHP are non-market based.

Consultation Question 13: Do you agree with the RAs' interpretation of Article 13(6) and the introduction of a new hierarchy for the application of non-market-based downward redispatching?

Response: We concur with IWEA's response in relation to this matter.

Consultation Question 14: Do you agree with the RAs' interpretation of Article 13(7) and the view that the provision of financial compensation to firm generators subject to curtailment based on net revenues from the day-ahead market including any financial support that would have been received represents an unjustifiably high level of compensation?

Response: Coillte does not agree, in line with IWEA's arguments, that this represents an unreasonably high level of compensation. The compensation should be evaluated at a generator level.

Coillte, Dublin Road, Newtownmountkennedy, Co. Wicklow, A63 DN25, Ireland.
T 1890 367 378 F +353 1 201 1199 E info@coillte.ie W www.coillte.ie

Consultation Question 15: Which of the options on compensation for curtailment presented above do you view to be most appropriate to adopt in the SEM? Are there additional options that the RAs should consider around compensation for curtailment?

Response: Coillte refers the SEM Committee to IWEA's response.

Coillte, Dublin Road, Newtownmountkennedy, Co. Wicklow, A63 DN25, Ireland.
T 1890 367 378 F +353 1 201 1199 E info@coillte.ie W www.coillte.ie